



FORM PTO-1390 (Modified) (REV 11-2000)		U.S. DEPARTMENT OF COMMERCE PATENT AND TRADEMARK OFFICE		ATTORNEY'S DOCKET NUMBER <b>8830-38</b>	
<b>TRANSMITTAL LETTER TO THE UNITED STATES</b> <b>DESIGNATED/ELECTED OFFICE (DO/EO/US)</b> <b>CONCERNING A FILING UNDER 35 U.S.C. 371</b>				U.S. APPLICATION NO. (IF KNOWN, SEE 37 CFR <b>10/088128</b>	
				PRIORITY DATE CLAIMED <b>September 14, 1999</b>	
INTERNATIONAL APPLICATION NO. <b>PCT/GB00/03491</b>		INTERNATIONAL FILING DATE <b>September 12, 2000</b>			
TITLE OF INVENTION <b>Apparatus And Methods Relating To Downhole Operations</b>					
APPLICANT(S) FOR DO/EO/US <b>Andre Martin Van der Ende and John Cope</b>					
Applicant herewith submits to the United States Designated/Elected Office (DO/EO/US) the following items and other information:					
<ol style="list-style-type: none"> <li>1. <input checked="" type="checkbox"/> This is a <b>FIRST</b> submission of items concerning a filing under 35 U.S.C. 371.</li> <li>2. <input type="checkbox"/> This is a <b>SECOND</b> or <b>SUBSEQUENT</b> submission of items concerning a filing under 35 U.S.C. 371.</li> <li>3. <input checked="" type="checkbox"/> This is an express request to begin national examination procedures (35 U.S.C. 371(f)). The submission must include items (5), (6), (9) and (24) indicated below.</li> <li>4. <input checked="" type="checkbox"/> The US has been elected by the expiration of 19 months from the priority date (Article 31).</li> <li>5. <input checked="" type="checkbox"/> A copy of the International Application as filed (35 U.S.C. 371 (c) (2)) <ol style="list-style-type: none"> <li>a. <input type="checkbox"/> is attached hereto (required only if not communicated by the International Bureau).</li> <li>b. <input checked="" type="checkbox"/> has been communicated by the International Bureau.</li> <li>c. <input type="checkbox"/> is not required, as the application was filed in the United States Receiving Office (RO/US).</li> </ol> </li> <li>6. <input type="checkbox"/> An English language translation of the International Application as filed (35 U.S.C. 371(c)(2)). <ol style="list-style-type: none"> <li>a. <input type="checkbox"/> is attached hereto.</li> <li>b. <input type="checkbox"/> has been previously submitted under 35 U.S.C. 154(d)(4).</li> </ol> </li> <li>7. <input checked="" type="checkbox"/> Amendments to the claims of the International Application under PCT Article 19 (35 U.S.C. 371 (c)(3)) <ol style="list-style-type: none"> <li>a. <input type="checkbox"/> are attached hereto (required only if not communicated by the International Bureau).</li> <li>b. <input type="checkbox"/> have been communicated by the International Bureau.</li> <li>c. <input type="checkbox"/> have not been made; however, the time limit for making such amendments has NOT expired.</li> <li>d. <input checked="" type="checkbox"/> have not been made and will not be made.</li> </ol> </li> <li>8. <input type="checkbox"/> An English language translation of the amendments to the claims under PCT Article 19 (35 U.S.C. 371(c)(3)).</li> <li>9. <input type="checkbox"/> An oath or declaration of the inventor(s) (35 U.S.C. 371 (c)(4)).</li> <li>10. <input type="checkbox"/> An English language translation of the annexes to the International Preliminary Examination Report under PCT Article 36 (35 U.S.C. 371 (c)(5)).</li> <li>11. <input checked="" type="checkbox"/> A copy of the International Preliminary Examination Report (PCT/IPEA/409).</li> <li>12. <input checked="" type="checkbox"/> A copy of the International Search Report (PCT/ISA/210).</li> </ol>					
<b>Items 13 to 20 below concern document(s) or information included:</b> <ol style="list-style-type: none"> <li>13. <input checked="" type="checkbox"/> An Information Disclosure Statement under 37 CFR 1.97 and 1.98.</li> <li>14. <input type="checkbox"/> An assignment document for recording. A separate cover sheet in compliance with 37 CFR 3.28 and 3.31 is included.</li> <li>15. <input checked="" type="checkbox"/> A <b>FIRST</b> preliminary amendment.</li> <li>16. <input type="checkbox"/> A <b>SECOND</b> or <b>SUBSEQUENT</b> preliminary amendment.</li> <li>17. <input type="checkbox"/> A substitute specification.</li> <li>18. <input type="checkbox"/> A change of power of attorney and/or address letter.</li> <li>19. <input type="checkbox"/> A computer-readable form of the sequence listing in accordance with PCT Rule 13ter.2 and 35 U.S.C. 1.821 - 1.825.</li> <li>20. <input type="checkbox"/> A second copy of the published international application under 35 U.S.C. 154(d)(4).</li> <li>21. <input type="checkbox"/> A second copy of the English language translation of the international application under 35 U.S.C. 154(d)(4).</li> <li>22. <input checked="" type="checkbox"/> Certificate of Mailing by Express Mail</li> <li>23. <input checked="" type="checkbox"/> Other items or information:</li> </ol>					
<b>Courtesy Copy of Publication PCT/GB00/03491</b> <b>Unexecuted Declaration and Power of Attorney</b> <b>Express Mail Label No. EL 931090748 US</b>					

U.S. APPLICATION NO. (IF KNOWN, SEE 37 CFR 1.101)		INTERNATIONAL APPLICATION NO.		ATTORNEY'S DOCKET NUMBER	
10/088128		PCT/GB00/03491		8830-38	
24. The following fees are submitted:.				CALCULATIONS PTO USE ONLY	
BASIC NATIONAL FEE ( 37 CFR 1.492 (a) (1) - (5) ) :					
<input type="checkbox"/> Neither international preliminary examination fee (37 CFR 1.482) nor international search fee (37 CFR 1.445(a)(2)) paid to USPTO and International Search Report not prepared by the EPO or JPO . . . . .				\$1040.00	
<input checked="" type="checkbox"/> International preliminary examination fee (37 CFR 1.482) not paid to USPTO but International Search Report prepared by the EPO or JPO . . . . .				\$890.00	
<input type="checkbox"/> International preliminary examination fee (37 CFR 1.482) not paid to USPTO but international search fee (37 CFR 1.445(a)(2)) paid to USPTO . . . . .				\$740.00	
<input type="checkbox"/> International preliminary examination fee (37 CFR 1.482) paid to USPTO but all claims did not satisfy provisions of PCT Article 33(1)-(4) . . . . .				\$710.00	
<input type="checkbox"/> International preliminary examination fee (37 CFR 1.482) paid to USPTO and all claims satisfied provisions of PCT Article 33(1)-(4) . . . . .				\$100.00	
ENTER APPROPRIATE BASIC FEE AMOUNT =				\$890.00	
Surcharge of \$130.00 for furnishing the oath or declaration later than <input type="checkbox"/> 20 <input type="checkbox"/> 30 months from the earliest claimed priority date (37 CFR 1.492 (e)).				\$0.00	
CLAIMS	NUMBER FILED	NUMBER EXTRA	RATE		
Total claims	35 - 20 =	15	x \$18.00	\$270.00	
Independent claims	8 - 3 =	5	x \$84.00	\$420.00	
Multiple Dependent Claims (check if applicable)			<input type="checkbox"/>	\$0.00	
TOTAL OF ABOVE CALCULATIONS =				\$1,580.00	
<input checked="" type="checkbox"/> Applicant claims small entity status. See 37 CFR 1.27). The fees indicated above are reduced by 1/2.				\$790.00	
SUBTOTAL =				\$790.00	
Processing fee of \$130.00 for furnishing the English translation later than <input type="checkbox"/> 20 <input type="checkbox"/> 30 months from the earliest claimed priority date (37 CFR 1.492 (f)).				\$0.00	
TOTAL NATIONAL FEE =				\$790.00	
Fee for recording the enclosed assignment (37 CFR 1.21(h)). The assignment must be accompanied by an appropriate cover sheet (37 CFR 3.28, 3.31) (check if applicable).			<input type="checkbox"/>	\$0.00	
TOTAL FEES ENCLOSED =				\$790.00	
				Amount to be: refunded	\$
				charged	\$
a. <input checked="" type="checkbox"/> A check in the amount of \$790.00 to cover the above fees is enclosed.					
b. <input type="checkbox"/> Please charge my Deposit Account No. in the amount of to cover the above fees. A duplicate copy of this sheet is enclosed.					
c. <input checked="" type="checkbox"/> The Commissioner is hereby authorized to charge any additional fees which may be required, or credit any overpayment to Deposit Account No. 50-0573 A duplicate copy of this sheet is enclosed.					
d. <input type="checkbox"/> Fees are to be charged to a credit card. WARNING: Information on this form may become public. Credit card information should not be included on this form. Provide credit card information and authorization on PTO-2038.					
NOTE: Where an appropriate time limit under 37 CFR 1.494 or 1.495 has not been met, a petition to revive (37 CFR 1.137(a) or (b)) must be filed and granted to restore the application to pending status.					
SEND ALL CORRESPONDENCE TO:					
ROBERT E. CANNUSCIO Drinker Biddle & Reath LLP One Logan Square 18th and Cherry Streets Philadelphia, Pennsylvania 19103-6996 (215) 988-3303 (215) 988-2757 Fax					
 23973 PATENT TRADEMARK OFFICE					
 SIGNATURE					
ROBERT E. CANNUSCIO NAME					
36,469 REGISTRATION NUMBER					
March 14, 2002 DATE					

PATENT

Attorney Docket No.:

8830-38

IN THE UNITED STATES PATENT AND TRADEMARK OFFICE

In re: Patent application of :  
Andre Martin Van Der Ende and :  
John Cope :  
Serial No.: Not Yet Assigned : International Application :  
PCT/GB00/03491 :  
Filed: Herewith : International Filing Date:  
September 12, 2000 :  
For: Apparatus and Methods Relating to :  
Downhole Operations :

PRELIMINARY AMENDMENT

Commissioner for Patents  
Box PCT  
Washington, D.C. 20231

Sir:

Prior to examination in the United States Patent and Trademark Office, please make the following amendments in the above-identified application in order to place it in condition for examination.

<p style="text-align: center;">CERTIFICATE OF MAILING UNDER 37 C.F.R. 1.10</p> <p>EXPRESS MAIL Mailing Label Number: <u>EL 931090748 US</u> Date of Deposit: <u>March 14, 2002</u></p> <p>I hereby certify that this correspondence, along with any paper referred to as being attached or enclosed, and/or fee, is being deposited with the United States Postal Service, "EXPRESS MAIL-POST OFFICE TO ADDRESSEE" service under 37 C.F.R. 1.10, on the date indicated above, and addressed to: Commissioner for Patents, Washington, D.C. 20231.</p> <p style="text-align: right;"><i>Therese McKinley</i> _____ Signature of person mailing page</p> <p style="text-align: right;">Therese McKinley _____ Type or print name of person</p>
--

## **AMENDMENT**

Please amend the application as follows, without prejudice.

### **In the Specification:**

Insert the following on page 1, line 3.

#### **--Field of the Invention--**

Insert the following on page 1, line 8.

#### **--Background of the Invention--**

Insert the following on Page 5, line 3.

#### **--Summary of the Invention--**

Insert the following on Page 12, line 16.

#### **--Brief Description of the Drawings--**

Insert the following on Page 13, line 3.

#### **--Detailed Description of the Embodiments--**

### **In the Claims:**

Please amend the claims as follows. (A marked up copy of the claims is included in the Appendix to this Preliminary Amendment.)

3. (Amended) An apparatus according to claim 1, wherein the transmitter is further associated with, provided on, or an integral part of a tool string.
5. (Amended) An apparatus according to claim 3, wherein the transmitter transmits data collected or generated by the downhole tool or the like to the receiver.
6. (Amended) An apparatus according to claim 1, wherein the receiver is located at, or near, the surface of the wellbore.
7. (Amended) An apparatus according to claim 1, wherein the distance travelled by the downhole tool, the status of the downhole tool or other parameters of the downhole tool, can be transmitted to the receiver.

8. (Amended) Apparatus according to claim 1, wherein the wireline is electrically insulated.
9. (Amended) Apparatus according to claim 1, wherein the wireline is sheathed to facilitate electrical insulation.
13. (Amended) A slickline according to claim 11, wherein the coating comprises a stress/impact sensitive material.
14. (Amended) A slickline according to claim 11, wherein the insulating coating comprises at least one enamel material.
17. (Amended) Apparatus according to claim 15, wherein the apparatus includes transmission means for transmitting data collected by the at least two sensors to a receiver located remotely from the apparatus.
19. (Amended) Apparatus according to claim 17, wherein the sensors are coupled at or near a downhole tool whereby the distance travelled by the tool, and the location of the tool within the wellbore, can be calculated.
20. (Amended) Apparatus according to claim 17, wherein the wireline is electrically insulated.
24. (Amended) A downhole tool according to claim 22, wherein the coupling means comprises a rope-socket.
26. (Amended) A downhole tool according to claim 20, wherein the downhole tool is powered by a DC power supply.
30. (Amended) Apparatus according to claim 28, wherein the transmitter facilitates the transmission of data collected by the sensors to the receiver.

31. (Amended) Apparatus according to claim 28, wherein the transmission means comprises a transmitter.
32. (Amended) Apparatus according to claim 28, wherein the receiver is located at, or near, the surface of the borehole.
33. (Amended) Apparatus according to claim 26, wherein the apparatus is arranged whereby it can facilitate two-way communication between the downhole tool and the receiver.
34. (Amended) Apparatus according to claim 28, wherein the sensors comprise electric or magnetic sensors which are coupled to the downhole tool wherein a discontinuity of the respective electric or magnetic connection triggers a signal by each sensor.
35. (Amended) Apparatus according to claim 29, wherein the wireline is electrically insulated.

**REMARKS**

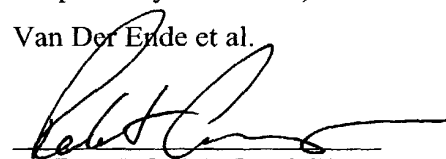
Claims 1-35 are pending in the application. Claims 3, 5-9, 13, 14, 17, 19, 20, 24, 26, 30-35 have been modified to remove multiple dependencies. Sub-headings have been added to the description. No new matter has been introduced.

Applicants look forward to an early action on the merits.

Respectfully Submitted,

Van Der Ende et al.

BY



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**Appendix - Marked Up Version of Amended Claims**

3. (Amended) An apparatus according to [either of ]claim[s] 1[ or 2], wherein the transmitter is further associated with, provided on, or an integral part of a tool string.
5. (Amended) An apparatus according to [either of ]claim[s] 3[ or 4], wherein the transmitter transmits data collected or generated by the downhole tool or the like to the receiver.
6. (Amended) An apparatus according to [any preceding ]claim\_1, wherein the receiver is located at, or near, the surface of the wellbore.
7. (Amended) An apparatus according to [any preceding ]claim\_1, wherein the distance travelled by the downhole tool, the status of the downhole tool or other parameters of the downhole tool, can be transmitted to the receiver.
8. (Amended) Apparatus according to [any preceding ]claim\_1, wherein the wireline is electrically insulated.
9. (Amended) Apparatus according to [any preceding ]claim\_1, wherein the wireline is sheathed to facilitate electrical insulation.
13. (Amended) A slickline according to [either of ]claim[s] 11[ or 12], wherein the coating comprises a stress/impact sensitive material.
14. (Amended) A slickline according to [any of ]claim[s] 11[ to 13], wherein the insulating coating comprises at least one enamel material.
17. (Amended) Apparatus according to [either of ]claim[s] 15 [ or 16], wherein the apparatus includes transmission means for transmitting data collected by the at least two sensors to a receiver located remotely from the apparatus.

19. (Amended) Apparatus according to [either of ]claim[s] 17[ or 18], wherein the sensors are coupled at or near a downhole tool whereby the distance travelled by the tool, and the location of the tool within the wellbore, can be calculated.
20. (Amended) Apparatus according to [any of ]claim[s] 17[ to 19], wherein the wireline is electrically insulated.
24. (Amended) A downhole tool according to [either of ]claim[s] 22[ or 23], wherein the coupling means comprises a rope-socket.
26. (Amended) A downhole tool according to [any of ]claim[s] 20[ to 23], wherein the downhole tool is powered by a DC power supply.
30. (Amended) Apparatus according to [either of ]claim[s] 28[ or 29], wherein the transmitter facilitates the transmission of data collected by the sensors to the receiver.
31. (Amended) Apparatus according to [ any of]claim[s] 28[ to 30], wherein the transmission means comprises a transmitter.
32. (Amended) Apparatus according to [any of ]claim[s] 28[ to 31], wherein the receiver is located at, or near, the surface of the borehole.
33. (Amended) Apparatus according to [any of ]claim[s] 26[ to 30], wherein the apparatus is arranged whereby it can facilitate two-way communication between the downhole tool and the receiver.
34. (Amended) Apparatus according to [any of ]claim[s] 28[ to 32], wherein the sensors comprise electric or magnetic sensors which are coupled to the downhole tool wherein a discontinuity of the respective electric or magnetic connection triggers a signal by each sensor.
35. (Amended) Apparatus according to [any of ]claim[s] 29[ to 34], wherein the wireline is electrically insulated.



1 "Apparatus and Methods Relating to Downhole  
2 Operations"

3  
4 The present invention relates to apparatus and  
5 methods relating to downhole operations, and  
6 particularly, but not exclusively, to wireline  
7 operations.

8  
9 Wireline is a term commonly used for the operation of  
10 deploying and/or retrieving tools or the like using a  
11 wire, the wire being one of several different types  
12 of construction. For example, slicklines are wires  
13 which comprise a single strand steel or alloy piano-  
14 type wire which currently have a diameter of around  
15 0.092 inches to 0.125 inches (approximately 2.34mm to  
16 3.17mm) in use, with the possibility of increasing  
17 this to 0.25 inches (approximately 6.25mm) in the  
18 future.

19

1 Wirelines may also be of a braided construction which  
2 can also carry single or multiple electrical  
3 conductor wires through its core and is typically of  
4 a diameter in the order of 3/16 of an inch  
5 (approximately 4.76mm) or above. Slick tubing, more  
6 commonly known as coiled tubing, is in the form of a  
7 continuous hollow-cored steel or alloy tubing which  
8 is usually of a diameter greater than the preceding  
9 types of wireline.

10

11 Wirelines are conventionally used to insert and/or  
12 retrieve downhole tools from a wellbore or the like.  
13 The downhole tools are typically deployed to perform  
14 various downhole functions and operations such as the  
15 deployment and setting of plugs in order to isolate a  
16 section of the wellbore. It is advantageous and  
17 often essential to know the distance of travel of the  
18 wireline so that the location of the tool within the  
19 wellbore is known.

20

21 Wirelines are conventionally stored on a winching  
22 unit typically located at the surface in the  
23 proximity of the top of a borehole. It should be  
24 noted that "surface" in this context is to be  
25 understood as being either atmospheric above ground  
26 or sea level, or aquatic above the seabed. Although  
27 the methods and apparatus employed in wireline  
28 operations vary in detail, the wireline is commonly  
29 introduced into the wellbore (the wellbore  
30 conventionally being cased, as is known) via a series  
31 of sheaves or guide rollers. The sheaves or guide

1     rollers facilitate, in the first instance, a  
2     substantially vertical orientation of the wireline.  
3     The wireline passes through a substantially  
4     vertically-orientated superstructure tube having an  
5     internal open-ended bore, the tube being positioned  
6     on top of a wellhead. Thus, any downhole tool can be  
7     introduced into the wellbore.

8  
9     The wireline is coupled at its distal (downhole) end  
10    to the downhole tool, typically via a part of the  
11    tool known as a rope-socket. The rope-socket is  
12    conventionally used to provide a mechanical  
13    connection between the wireline and the downhole tool  
14    (or a string of downhole tools known as a tool  
15    string).

16  
17    The conventional method of measuring the downhole  
18    tool depth is to run the wireline against a measuring  
19    wheel which is a pulley wheel of known diameter. It  
20    should be noted that use of "depth" in this context  
21    is to be understood as being the trajectory length of  
22    the downhole tool, which may be different from  
23    conventional depth if the wellbore is deviated, for  
24    example. In order to calculate the distance of  
25    travel of the wireline, a number of variable factors  
26    must be known. It is a prerequisite that the  
27    rotational direction of the pulley wheel, the number  
28    of revolutions thereof, the diameter of the pulley  
29    wheel and, depending upon the type of pulley wheel  
30    (that is, whether a point-type contact or arc for  
31    example), the diameter of the wireline, must all be

1 known before the distance of travel of the wireline  
2 within the wellbore can be calculated.

3

4 However, with this conventional method for  
5 calculating the distance of travel of the wireline, a  
6 number of factors can render the calculation  
7 inaccurate. The occurrence of wheel slippage, the  
8 stretch of the wireline (due to the weight of the  
9 wireline itself, and/or the weight of the tool string  
10 which is attached thereto), the effect of friction  
11 and the well-contained fluid buoyancy all contribute  
12 to decrease the accuracy of the tool depth  
13 measurement.

14

15 In order to improve the accuracy of this conventional  
16 depth measurement, it is known to combine the  
17 measured tensile load, the known stretch co-efficient  
18 of the wireline, and the conventionally measured tool  
19 depth as described above, to recalculate the tool  
20 depth measurement on a continuous basis (ie in real  
21 time) using a processing means, such as a computer or  
22 the like.

23

24 However, the accuracy of the aforementioned depth  
25 measurement correction method relies on an  
26 experimentally determined constant (ie the stretch  
27 co-efficient of the wireline) and the surface  
28 measurements on the wireline. The resulting  
29 correction does not include the significant combined  
30 effect that well fluid temperature, tool buoyancy and

1 well geometry have on the accuracy of the depth  
2 correction.

3  
4 According to a first aspect of the present invention  
5 there is provided distance measurement apparatus for  
6 measuring the distance travelled by a wireline, the  
7 apparatus comprising at least one sensor coupled to  
8 the wireline wherein the sensor is capable of sensing  
9 known locations in a wellbore.

10

11 The wireline is typically a slickline.

12

13 According to a second aspect of the present invention  
14 there is provided a method of measuring the distance  
15 travelled by a wireline, the method comprising the  
16 steps of coupling at least one sensor to the  
17 wireline, the at least one sensor being capable of  
18 sensing known locations in a wellbore; running the  
19 wireline into the wellbore; calculating the depth of  
20 the at least one sensor using any conventional means;  
21 generating a signal when the at least one sensor  
22 passes said known locations; using the signal to  
23 calculate a depth correction factor; and correcting  
24 the calculated depth using the depth correction  
25 factor.

26

27 Preferably, the apparatus includes transmission means  
28 for transmitting data collected by the at least one  
29 sensor to a receiver located remotely from the  
30 apparatus. Preferably, the wireline is capable of  
31 acting as an antenna for the transmission means.

1  
2 The sensor may be coupled to the wireline at any  
3 point thereon, or may form an integral part thereof.  
4 The sensor is preferably coupled at or near a  
5 downhole tool whereby the distance travelled by the  
6 tool (and thus its location within the wellbore) can  
7 be calculated. Alternatively, the sensor may form  
8 part of a downhole tool or the like.

9  
10 The sensor typically comprises a magnetic field  
11 sensor, and preferably an array of magnetic field  
12 sensors. The array of magnetic field sensors are  
13 typically provided on a common horizontal plane.  
14 Alternatively, the sensor may comprise a radio  
15 frequency (RF) sensor, and preferably an array  
16 thereof. Where an RF sensor is used, the wellbore is  
17 typically provided with RF tags at known locations.

18  
19 The wireline is preferably electrically insulated.  
20 The wireline may be sheathed to facilitate electrical  
21 insulation. Alternatively, the wireline may be  
22 passed through a stuffing box or the like to  
23 facilitate electrical insulation and/or isolation.

24  
25 According to a third aspect of the present invention  
26 there is provided a downhole tool comprising coupling  
27 means to allow the tool to be attached to a wireline,  
28 at least one sensor capable of detecting known  
29 locations in a wellbore and generating a signal  
30 indicative thereof, and a transmission means capable  
31 of transmitting the signal.

1  
2 There is also provided a method of tracking a member  
3 in a wellbore, the method comprising providing a  
4 sensor on the member, inserting the member and sensor  
5 into the wellbore, obtaining information indicating  
6 the position of the sensor in the wellbore, and  
7 determining the distance travelled by said member  
8 from said sensor information.

9  
10 The wireline is preferably used as an antenna for the  
11 transmission means.

12  
13 The coupling means typically comprises a rope-socket.  
14 The rope-socket is preferably provided with signal  
15 coupling means to couple the signal generated by the  
16 transmission means to the wireline.

17  
18 The sensor typically comprises a magnetic field  
19 sensor, and preferably an array of magnetic field  
20 sensors. The array of magnetic field sensors are  
21 typically provided on a common horizontal plane.  
22 Alternatively, the sensor may comprise a radio  
23 frequency (RF) sensor, and preferably an array  
24 thereof. The array of RF sensors are typically  
25 provided on a common horizontal plane.

26  
27 The downhole tool is preferably powered by a DC power  
28 supply, and most preferably a local DC power supply.  
29 The DC power supply typically comprises at least one  
30 battery.

31

1 According to a fourth aspect of the present invention  
2 there is provided a wireline wherein the wireline is  
3 provided with an insulating coating.

4  
5 The insulating coating is typically an outer coating  
6 of the wireline. The wireline typically comprises a  
7 slickline.

8  
9 The insulating coating typically comprises at least  
10 one enamel material. The enamel material typically  
11 consists of one or more layers of coating whereby  
12 each individual layer adds to the overall required  
13 coating properties. Additionally, each layer of  
14 enamel material preferably has the required bonding,  
15 flexibility and stretch characteristics at least  
16 equal to those of the wireline.

17  
18 The enamel material can typically be applied to the  
19 wireline by firstly applying a thin layer of  
20 adhesive, such as nylon or other suitable primer.  
21 Thereafter, one or more layers of an enamel material  
22 such as polyester, polyamide, polyamide-imide,  
23 polycarbonates, polysulfones, polyester imides,  
24 polyether, ether ketone, polyurethane, nylon, epoxy,  
25 equilibrating resin, or alkyd resin or theic  
26 polyester, or a combination thereof, are preferably  
27 applied. The enamel material is preferably  
28 polyamide-imide.

29  
30 According to a fifth aspect of the present invention  
31 there is provided a communication system for use in a



1 wellbore, the system comprising a transmitter coupled  
2 to a wireline, and a receiver located remotely from  
3 the transmitter, wherein the wireline is capable of  
4 acting as an antenna for the transmitter.

5  
6 The wireline is typically a slickline.

7  
8 The transmitter is typically associated with,  
9 provided on, or an integral part of a downhole tool  
10 or tool string, whereby the downhole tool or tool  
11 string is typically suspended by the wireline.

12  
13 The transmitter typically facilitates the  
14 transmission of data collected by the downhole tool  
15 or the like to the receiver. The transmission means  
16 typically comprises a transmitter. The receiver is  
17 typically located at, or near, the surface.

18  
19 Optionally, the communication system is arranged  
20 whereby it can facilitate two-way communication  
21 between the downhole tool and the receiver. In this  
22 embodiment, a transmitter and a receiver are  
23 typically located downhole. Additionally, a  
24 transmitter and a receiver are also located at, or  
25 near, the surface. The transmitter and receiver at  
26 the surface and/or downhole may be replaced by a  
27 transceiver located downhole and at, or near, the  
28 surface.

29  
30 The transmitter may be coupled to the wireline at any  
31 point thereon, or may form a part thereof. The

1 transmitter is typically coupled at or near a  
2 downhole tool whereby the distance travelled by the  
3 tool, the status of the tool or other parameters of  
4 the tool, can be transmitted to the receiver.  
5 Alternatively, the transmitter may form an integral  
6 part of a downhole tool.

7  
8 The wireline is preferably electrically insulated.  
9 The wireline may be sheathed to facilitate electrical  
10 insulation. Alternatively, the wireline may be  
11 passed through a stuffing box or the like to  
12 facilitate electrical insulation and/or isolation.

13  
14 According to a sixth aspect of the present invention  
15 there is provided apparatus for indicating the  
16 configuration of a downhole tool or tool string, the  
17 apparatus comprising at least one sensor capable of  
18 sensing a change in the configuration of the downhole  
19 tool or tool string and generating a signal  
20 indicative thereof, and a transmission means  
21 electrically coupled to the at least one sensor for  
22 transmitting the signal to a receiver.

23  
24 The downhole tool is preferably suspended in a  
25 borehole using a wireline, and the wireline is  
26 preferably capable of acting as an antenna for the  
27 transmission means.

28  
29 The transmitter typically facilitates the  
30 transmission of data collected by the sensor to the  
31 receiver. The transmission means typically comprises

1 a transmitter. The receiver is typically located at,  
2 or near, the surface.

3

4 Optionally, the communication system is arranged  
5 whereby it can facilitate two-way communication  
6 between the downhole tool and the receiver. In this  
7 embodiment, a transmitter and a receiver are  
8 typically located downhole. Additionally, a  
9 transmitter and a receiver are also located at, or  
10 near, the surface. The transmitter and receiver at  
11 the surface and/or downhole may be replaced by a  
12 transceiver located downhole and at, or near, the  
13 surface.

14

15 The sensor typically comprises an electric or  
16 magnetic sensor which is coupled to the downhole tool  
17 wherein a discontinuity of the electric or magnetic  
18 connection triggers a signal, or a plurality of  
19 signals. These signals can then be transmitted to  
20 the surface to indicate the status of the tool. In  
21 one embodiment, the sensor may be coupled between a  
22 tool string and a downhole tool which is to be  
23 deployed into a wellbore, wherein discontinuity of  
24 the electric or magnetic connection indicates that  
25 the tool has been deployed. Alternatively, the  
26 sensor may be coupled to a distal end of the tool  
27 string, and the downhole tool which is to be  
28 retrieved from a wellbore, is provided with a similar  
29 sensor, wherein continuity of the electric or  
30 magnetic connection indicates that the tool has been  
31 retrieved.

1  
2 The sensor may also be coupled to part of a downhole  
3 tool which changes status during operation of the  
4 tool (ie a valve, sleeve or the like) wherein the  
5 sensor indicates the status of the part of the  
6 downhole tool by a change in continuity.

7  
8 The sensor may comprise a proximity sensor, magnetic  
9 sensor or the like.

10  
11 The wireline is preferably electrically insulated.  
12 The wireline may be sheathed to facilitate electrical  
13 insulation. Alternatively, the wireline may be  
14 passed through a stuffing box or the like to  
15 facilitate electrical insulation and/or isolation.

16  
17 Embodiments of the present invention shall now be  
18 described, by way of example only, with reference to  
19 the accompanying drawings in which:

20 Fig. 1 is a part cross-section of a downhole  
21 tool according to a third aspect of the present  
22 invention;

23 Fig. 2 is a schematic diagram of a typical  
24 wireline apparatus;

25 Fig. 3 is an enlarged view of part of the  
26 wireline apparatus of Fig. 2;

27 Fig. 4 is a schematic diagram of a transmitter  
28 which forms part of an electronic system for use  
29 with the downhole tool of Fig. 1; and

30 Fig. 5 is a schematic diagram of a receiver  
31 which forms part of an electronic system located

1 at the surface for receiving signals from the  
2 downhole tool of Fig. 1.

3  
4 Referring to the drawings, Fig. 1 shows an embodiment  
5 of part of a distance measuring apparatus, generally  
6 designated 10. The apparatus 10 includes a slickline  
7 12. Although reference will be made herein to use of  
8 a slickline, it will be appreciated that other types  
9 of wireline may be used, such as a braided line or  
10 cable, coiled tubing or the like. Slickline 12 is  
11 typically stored on a reel 14 which forms part of a  
12 winching device 16 (Fig. 2), commonly known in the  
13 art as a wireline winch unit. The winching device 16  
14 is typically located at the surface. It should be  
15 noted that "surface" in this context is to be  
16 understood as being either atmospheric above ground  
17 or sea level, or aquatic above a seabed.

18  
19 The slickline 12 is introduced into a cased wellbore  
20 (not shown) via a plurality of sheaves or guide  
21 rollers, as illustrated in Fig. 2. The sheaves or  
22 guide rollers divert the slickline 12 into a  
23 substantially vertical orientation. The slickline 12  
24 passes through a vertically-orientated superstructure  
25 tube 18 which has an internal open-ended bore, the  
26 tube 18 being positioned above a wellhead, generally  
27 designated 20.

28  
29 Referring to Fig. 3, there is shown in more detail a  
30 part of the slickline apparatus of Fig. 2. Located  
31 at an upper end of the tube 18 is a sheave wheel 22

1 which guides the slickline 12 from a substantially  
2 upward direction through 180° to a substantially  
3 downward direction. The slickline 12 then passes  
4 through a stuffing box, generally designated 24 in  
5 Fig. 3, which typically includes an internal blow-out  
6 preventer (BOP) 26.

7  
8 The slickline 12 enters the tube 18 and continues  
9 downward therethrough and into a main BOP 28 and the  
10 wellhead 20.

11  
12 The slickline 12 is coupled at a lower end thereof to  
13 a part of a downhole tool commonly known as a rope-  
14 socket 30 (Fig. 1). The main function of a rope-  
15 socket 30 is to provide a mechanical linkage between  
16 the slickline 12 and the tool or tool string. The  
17 mechanical linkage may be any one of a plurality of  
18 different forms, but is typically a self-tightening  
19 means. In the embodiment shown in Fig. 1, the rope-  
20 socket 30 includes a wedge or wire retaining cone 34  
21 which engages in a correspondingly tapered retaining  
22 sleeve 36.

23  
24 The rope-socket 30 is also provided with a sealing  
25 means which seals around the slickline 12 to provide  
26 a seal between the rope-socket 30 and the well  
27 environment around the slickline 12. The sealing  
28 means typically comprises a seal or gasket 44 which  
29 isolates and insulates the interior of the rope-  
30 socket 30 from the well environment.

31

1 In the embodiment shown in Fig. 1, the rope-socket 30  
2 also provides an electrical coupling between the  
3 slickline 12 which is capable of acting as a  
4 transmitter/receiver radio frequency (RF) antenna and  
5 a downhole tool 32. The tool 32 typically comprises  
6 an upper sub 38 which is coupled (typically by  
7 threaded connection) to an intermediate sub 40, which  
8 is in turn coupled (typically by threaded connection)  
9 to a lower sub 42.

10

11 The upper sub 38 is provided with a screw thread 38t,  
12 typically in the form of a pin, which engages with a  
13 corresponding internal screw thread 30t, typically in  
14 the form of a box, on the rope-socket 30. These  
15 (threaded) connections 30t, 38t allow the rope-socket  
16 30 and tool 32 to be (mechanically) coupled together.

17

18 Additionally, the rope-socket 30 is provided with  
19 coupling means which electrically couples a metal or  
20 otherwise electrically conductive portion of the  
21 slickline 12 and a transmitter 46 (a transceiver  
22 typically being used to facilitate two-way  
23 communication) of the tool 32. The coupling means  
24 typically comprises an electrical terminal 48 which  
25 is electrically isolated from the body of the rope-  
26 socket 30 using an insulating sleeve 50.

27

28 The upper sub 38 of the tool 32 is provided with an  
29 electrical pin or contact plunger 52 which engages  
30 with the electrical terminal 48 within the rope-  
31 socket 30. The contact plunger 52 is typically

1 spring-loaded using spring 54 so that it can move  
2 longitudinally (with respect to a longitudinal axis  
3 of the tool 32) to facilitate coupling of the rope-  
4 socket 30 and the tool 32. A lower end of the  
5 plunger 52 is in contact with a main contactor 56  
6 which is electrically coupled to the transmitter 46.  
7 This facilitates coupling of signals generated by the  
8 transmitter 46 through the plunger 52 and the  
9 terminal 48 to the slickline 12, the slickline 12  
10 acting as an antenna for transmitting and/or  
11 receiving signals, as will be described.

12

13 The tool 32 is also provided with an array of field  
14 sensors 58 which are used to detect differences in  
15 the magnetic flux at the junctions of, or collars  
16 between, successive casing sections which are used to  
17 case the wellbore, whereby the location of the tool  
18 32 within the wellbore can be calculated, as will be  
19 described.

20

21 The tool 32 is preferably powered by a (local) direct  
22 current (DC) power source, typically comprising one  
23 or more batteries 60. The batteries 60 provide a  
24 local electrical power supply for the tool 32.

25 Conventionally, downhole tools are powered using a  
26 central conductor of a braided line to transmit  
27 electrical power to the tool from the surface.

28 However, there are substantial losses using this  
29 method, particularly where the tool is located some  
30 distance down the wellbore. In addition, the central  
31 conductor of the braided line is typically relatively



1 small in diameter and thus high voltage drops can be  
2 induced. Use of a local power supply (ie the  
3 batteries 60) obviates the need for an electrical  
4 power connection to the surface.

5  
6 The tool 32 may include a pressure sensor 62 which is  
7 electrically coupled to the transmitter 46 and when  
8 present can be used to measure the pressure external  
9 to the tool 32.

10  
11 Referring now to Fig. 4, there is shown a schematic  
12 diagram of a transmitter 46 which forms a part of an  
13 electronic system located within the tool 32. The  
14 batteries 60 provide electrical power to the system  
15 in general. On detection of a positive over-pressure  
16 to atmospheric level, that is after introducing the  
17 tool 32 into the tube 18 (Fig. 2) and opening of the  
18 wellhead 20 to allow well pressure to equalise in the  
19 tube 18, the pressure sensor 62 activates the  
20 magnetic field sensors 58.

21  
22 The magnetic field sensors 58 may be of the type  
23 described in German Patent Application Number DE-A1-  
24 19711781.3 (Pepperl + Fuchs GmbH), for example, and  
25 are typically mounted within a section of the tool 32  
26 which is at least partially manufactured from a  
27 conventional non-ferrous material. This ensures high  
28 sensitivity when detecting casing or collar joints.

29  
30 German Patent Application Number DE-A1-19711781.3  
31 describes use of the sensors 58 in conjunction with a

1 remnance inducing magnet ring. The wellbore casing  
2 sections described therein exhibit a weak magnetic  
3 remnance due to the influence of the earth's magnetic  
4 field, the difference in the magnetic flux and/or the  
5 history of previous well service operations. If the  
6 difference in the magnetic flux at the junctions  
7 between the wellbore casing sections is  
8 insufficiently weak or disorientated, it is  
9 advantageous to re-magnetise the casing sections by  
10 either running in a separate downhole tool provided  
11 with one or more axially orientated magnets prior to  
12 commencing the tool detection, or to incorporate one  
13 or more such magnets into the tool 32, or the tool  
14 string of which the tool 32 forms part.

15  
16 The plurality of sensors 58 are orientated to  
17 preferentially sense the locality and proximity of a  
18 collar or casing joint which the tool 32 passes, by  
19 detecting the variation or switch in magnetic flux at  
20 the junctions or collars between successive casing  
21 sections. It is preferred, but not essential, to  
22 have the sensors 58 disposed on a common horizontal  
23 plane within the tool 32. The latter, in combination  
24 with the series connection of the sensors 58 maximise  
25 the positive sensing of the collars or casing joints  
26 as the tool 32 passes.

27  
28 When a casing collar or joint is detected, power is  
29 supplied to the transmitter 46. The transmitter 46  
30 is located within the tool 32 and is electrically  
31 coupled to the batteries 60, the pressure sensor 62

1 and the magnetic field sensors 58 via suitable  
2 electrical connections within the tool 32.  
3 Alternatively, the transmitter 46 may be coupled  
4 thereto via a system of insulated downhole tool  
5 components which provide electrical connections  
6 isolated from the well environment, the electrical  
7 connections being suitable connectors between the  
8 separate downhole sections which make up the complete  
9 downhole tool string.

10  
11 The transmitter 46 may be of a type supplied by RS  
12 Components under catalogue number RS 740-449, which  
13 is designed to operate in conjunction with a 418 MHz  
14 FM transmitter module also supplied by RS Components  
15 under catalogue number RS 740-297. However, it  
16 should be noted that the transmitter specified above  
17 is only an example of one possible transmitter, and  
18 that there are many other possible transmitters and  
19 frequencies which could be utilised in it's place.  
20 The components identified above should be tested for  
21 conformity to the particular operational requirements  
22 and criteria and for operation in wellbore  
23 environments.

24  
25 The transmitter 46 typically has the facility for  
26 address coding (using DIL switch settings 66 in Fig.  
27 4), and data bit settings using either a DIL switch  
28 68 (Fig. 4) or driven by external switches, relay  
29 transistors or CMOS logic via an auxiliary connector,  
30 designated 70 in Fig. 4). DIL switch 68 is used to  
31 switch data channels (ie the four data channels

1 relating to each one of the sensors 58) on and off,  
2 typically using opto-electronic switches 69. Thus,  
3 the signal from any one, some or all of the sensors  
4 58 can be set to be transmitted. The output from the  
5 DIL switch 66 is typically processed by an encoder  
6 convertor 67 which encodes the address coding (as set  
7 by the DIL switch 66) into the transmission. RF  
8 transmission can be initiated by external contact  
9 closure and the provided link on the auxiliary  
10 connector 70 (eg, coupling TXEN to ground).

11

12 It will be appreciated that with the above described  
13 transmission method, the transmitter 46 is not  
14 permanently activated and allows only a single  
15 transmission upon external contact closure. The  
16 duration of the transmission may be altered by  
17 changing the values of RT, CT and/or RT2 and CT2  
18 respectively, but is typically in the order of 1  
19 second duration (set by default). The period of  
20 transmission may be determined as follows :-  
21  $2.2 \cdot RT \cdot CT$  (which changes the interval between  
22 transmission in seconds) and  $0.7 \cdot RT2 \cdot CT2$  (which  
23 changes the duration of the transmissions in  
24 seconds).

25

26 The transmitter 46 ground connection (ie from any  
27 point on the ground connection 64) and RFout  
28 connection 65 are electrically coupled to the rope-  
29 socket 30 using, for example, electrical connections  
30 within the tool 32 (or otherwise as described above)  
31 and the plunger 52 and electrical terminal 48

provided on the tool 32 and rope-socket 30 respectively (Fig. 1). These connections are shown schematically in Fig. 4, with the RFout connection 65 being coupled to the slickline 12 which acts as an antenna.

As previously noted, the slickline 12 acts as an antenna for this RF transmission and thus the slickline antenna 12 carries and guides the transmission towards the surface. The RF transmission (ie the electromagnetic (modulated) wave) contains encoded data which is radiated into free-space or any other antenna surrounding medium at or near the tube 18, for example. The precise location of where the RF transmission is radiated into free-space is not important, but it is typically at some point at the surface where the RF transmission can be radiated over a larger area.

Located within the radiation range of the transmitter antenna (ie the slickline 12), for example located at the surface or within the tube 18, is a receiver 80, shown in Fig. 5. Fig. 5 is a schematic diagram of the receiver 80 which forms a part of an electronic system located at or near the surface. The receiver 80 may be, for example, of the type supplied by RS Components under catalogue number RS 740-455, which is designed to operate in conjunction with a 418 MHz FM receiver module 84 supplied by RS Components under catalogue number RS 740-304. However, it should be noted that the receiver specified above is only an

1 example of one possible receiver, and that there are  
2 many other possible receivers which could be utilised  
3 in it's place. It should also be noted that the  
4 receiver 80 should be matched to the frequency of the  
5 transmitter 46. The components identified above  
6 should be tested for conformity to the particular  
7 operational requirements and criteria and for  
8 operation in wellbore environments.

9  
10 The receiver 80 typically has the facility for  
11 address coding (using suitable DIL switch settings on  
12 switch 82) to match and pair with the address code of  
13 the transmitter 46. The settings of the receiver  
14 board jumpers JP1 and JP2 determine the output  
15 configuration of the transmission from the tool 32.  
16 Jumper JP2 is used to select whether the output is  
17 high or low (ie the logic level) which selects  
18 whether the output on the four channels out 0 to out  
19 3 on an auxiliary connector 88) are either a logic  
20 high or a logic low. Jumper JP1 is used to select  
21 whether the output on the channels out 0 to out 3 are  
22 latched (ie permanently high or low) or intermittent.

23  
24 The receiver module 84 receives the signal from the  
25 antenna 12 at an RFin connection 86. The signal is  
26 then processed in the FM receiver module 84 and  
27 output to a decoder 90. The decoder 90 decodes the  
28 address coding from the transmission and thus the  
29 receiver 80 is only activated when the address of the  
30 transmitter 46 matches the address settings of the  
31 DIL switch 82 (ie the address of the receiver 80).

1 The output from the decoder 90 is then fed to a data  
2 selector 92 which automatically activates one, some  
3 or all of the output channels out 0 to out 3,  
4 depending upon which of the four channels have been  
5 activated by the settings of the DIL switch 68 on the  
6 transmitter 46. The output of the selector 92 is  
7 then fed to a seven stage darlington driver 94 which  
8 is used to drive the outputs on the auxiliary  
9 connector 88. The outputs of the auxiliary connector  
10 88, in particular the outputs out 0 to out 3 are  
11 typically coupled to a visual indicator (ie a light  
12 emitting diode (LED)) which can be used to allow a  
13 user to determine which of the sensors 58 detected a  
14 collar or casing joint. Alternatively, or  
15 additionally, the outputs of the auxiliary connector  
16 88 may be coupled to a processing means (eg a  
17 computer) located at or near the surface for further  
18 processing of the data.

19  
20 It should be noted that although the transmitter 46  
21 is shown coupled to four sensors 58 (Fig. 4) and thus  
22 has four channels, the transmitter 46 may be provided  
23 with more or less than four channels, depending upon  
24 the number and grouping of sensors 58 within tool 32.

25  
26 In use, the tool 32 is attached to the slickline 12  
27 as described above and introduced into a cased  
28 wellbore in a conventional manner. The casing can be  
29 of any type, that is, for example, either  
30 electrically conductive or semi-conductive  
31 ferromagnetic casing, or electrically non-conductive

1 or non-ferromagnetic casing. The casing string  
2 typically comprises of a plurality of casing lengths  
3 which are threadedly coupled together, thus making  
4 joints (or collars) therebetween.

5  
6 The tool 32 is lowered into the cased wellbore using  
7 the slickline 12. The slickline 12 is typically  
8 formed of a metal which has a high yield strength to  
9 weight ratio and is capable of supporting the tool 32  
10 (and any other tools which may form part of a  
11 downhole tool string). It will be appreciated that  
12 the slickline 12 should also be capable of  
13 functioning as a monopole antenna.

14  
15 The slickline 12 is preferably (but not essentially)  
16 electrically insulated and/or isolated using a thin  
17 outer coating of a flexible, non-conductive  
18 insulating material. It is preferred that the  
19 material should also be chemical, abrasion and  
20 temperature resistant to endure the hazardous  
21 downhole environments. The coating is typically an  
22 enamel coating.

23  
24 It should be noted that it may not be necessary to  
25 provide an insulating coating on the slickline 12.  
26 If a stuffing box or the like is used, the slickline  
27 12 will be electrically isolated by the stuffing box.  
28 However, this requires that the slickline 12 does not  
29 come into contact with any part of the conductive  
30 wellbore which may be difficult in deviated  
31 (horizontal) wells or the like. It is thus preferred



1 that the slickline 12 is coated with an insulating  
2 coating to ensure good electrical isolation. It  
3 should be noted that coating the slickline 12 with an  
4 enamel material also protects the metal wire (from  
5 which the slickline 12 is made) against corrosion.  
6 In addition, or alternatively, a corrosive chemical  
7 sensitive material(s) may be applied as a coating or  
8 part thereof on the slickline 12, and this would have  
9 the advantage that the presence of corrosive  
10 chemicals, such as H<sub>2</sub>S or CO<sub>2</sub> or nitrates, in the  
11 well would be indicated to the operator when the  
12 slickline 12 is removed from the well since the  
13 corrosive chemical sensitive material will be  
14 transformed; for example, the colour of the corrosive  
15 chemical sensitive material may change. In addition,  
16 or alternatively, a stress/impact sensitive  
17 material(s) may be applied as a coating or part  
18 thereof on the slickline 12, and this would have the  
19 advantage that mechanical damage to the slickline 12  
20 in the well would be indicated to the operator when  
21 the slickline 12 is removed from the well, since the  
22 stress/impact sensitive material will be transferred;  
23 for example, the colour of the impact/stress  
24 sensitive material may change.

25

26 The enamel material may consist of one or more layers  
27 of coating whereby each individual layer adds to the  
28 overall required coating properties. Additionally,  
29 each layer of enamel material preferably has the  
30 required bonding, flexibility and stretch  
31 characteristics at least equal to those of the metal

1 slickline 12 or coiled tubing. The thickness of the  
2 enamel material can vary depending upon the downhole  
3 conditions encountered, but is generally in the order  
4 of 10 to 100 microns.

5  
6 The enamel material can typically be applied to the  
7 slickline 12 by firstly applying a thin layer of  
8 adhesive, such as nylon or other suitable primer.  
9 Thereafter, one or more layers of an enamel material  
10 such as polyester, polyamide, polyamide-imide,  
11 polycarbonates, polysulfones, polyester imides,  
12 polyether, ether ketone, polyurethane, nylon, epoxy,  
13 equilibrating resin, or alkyd resin or theic  
14 polyester, or a combination thereof. The enamel  
15 material is preferably polyamide-imide.

16  
17 The conventional method of measuring downhole tool  
18 depth is to run the slickline 12 against the sheave  
19 wheel 22. It should be noted that use of "depth" in  
20 this context is understood as being the trajectory  
21 length of the downhole tool, which may be different  
22 from conventional depth if the wellbore is deviated,  
23 for example. In order to calculate the distance of  
24 travel of the slickline 12, a number of variable  
25 factors must be known. It is a prerequisite that the  
26 rotational direction of the sheave wheel 22, the  
27 number of revolutions thereof, the diameter of the  
28 sheave wheel 22 and, depending upon the type of  
29 sheave wheel 22 (that is, whether a point-type  
30 contact or arc for example), the diameter of the  
31 slickline 12, must all be known before the distance

1 of travel of the slickline 12 within the wellbore can  
2 be calculated (and thus the depth of the tool).

3

4 However, with this conventional method for  
5 calculating the distance of travel of the slickline  
6 12, a number of factors render the calculation  
7 inaccurate. The occurrence of wheel slippage, the  
8 stretch of the slickline 12 (whether due to the  
9 weight of the slickline 12 itself, or the weight of  
10 the tool string to which it is attached), the effect  
11 of friction and the well-contained fluid buoyancy all  
12 contribute to decrease the accuracy of the  
13 conventional tool depth measurement.

14

15 In order to improve the accuracy of this conventional  
16 depth measurement, it is known to combine the  
17 measured tensile load, the known stretch co-efficient  
18 of the slickline 12, and the conventionally measured  
19 tool depth as described above, to recalculate the  
20 tool depth measurement on a continuous (ie real time)  
21 basis using a processing means (eg a computer).

22

23 However, the accuracy of the aforementioned depth  
24 measurement correction method relies on an  
25 experimentally determined constant (ie the stretch  
26 co-efficient of the slickline 12) and the surface  
27 measurements of the weight of the slickline 12. The  
28 resulting correction does not include the significant  
29 combined effect that well fluid temperature, tool  
30 buoyancy and well geometry have on the accuracy of  
31 the depth correction.

1  
2 When the tool 32 detects a casing collar or joint  
3 during normal slickline operations at downhole tool  
4 travelling speed, the tool 32 will process the  
5 collected data at normal wireline operational speed  
6 using a processing device and signal generator 71  
7 (Fig. 4) which forms part of the transmitter 46. The  
8 processing device and signal generator 71  
9 communicates a signal (via a SAW oscillator 73 and  
10 418 MHz band-pass filter 75) indicative of the  
11 location of the collar or joint to the slickline 12  
12 which acts as an antenna. At the surface, this  
13 signal is received by the surface receiver 80 (Fig.  
14 5). The receiver 80 is coupled to the processing  
15 means (eg a computer) located at the surface and the  
16 signal from the tool 32 is used to calibrate the  
17 conventional measured depth against the known  
18 distance between the preceding collar or joint, or  
19 other known location. This distance is typically  
20 known from an existing record log of the individual  
21 casing lengths.

22  
23 A number of arrays of magnetic field sensors 58  
24 positioned on axially spaced-apart horizontal planes  
25 within the tool 32 (as shown in Fig. 1) can be used,  
26 each of the sensor arrays having their own channel as  
27 described above and being set at known (but not  
28 necessarily equal) distances along the longitudinal  
29 axis of the tool 32. This allows for increased  
30 accuracy of the calibration due to the repeated  
31 calibration against the detected collar or joint. It

1 should be noted that when using multiple arrays of  
2 sensors 58, only a single transmitter 46 and receiver  
3 80 need be used as each array 58 will have their own  
4 individual channel which can be selected or  
5 deselected as required.

6  
7 However, if the communication system is being used  
8 with other sensors within the tool, these other  
9 sensors may be coupled to another transmitter and  
10 receiver, the other transmitter and receiver  
11 including a different address coding. This allows  
12 multiple transmissions to multiple receivers 80 from  
13 multiple transmitters 46 using only one slickline 12  
14 as the antenna.

15  
16 The signal from the tool 32 is, for the purpose of  
17 the described tool depth measurement calibration, a  
18 measure of a known trajectory length of the tool 32  
19 in relation to a detected collar or casing joint end  
20 length (casing-section length calibration). This is  
21 dependent upon the configuration of tool 32 within  
22 the downhole tool or string. Alternatively, the  
23 signal is a measure of the trajectory length as  
24 travelled by the tool 32 in relation to the detected  
25 collar or casing joint as indicated by each separate  
26 positive signal from the tool 32 (downhole tool  
27 length calibration). For the casing section length  
28 calibration technique, the accuracy of the  
29 calibration may depend upon the accuracy and  
30 completeness of surveyed well details, that is the  
31 length of the individual casing sections and the

1 configuration thereof. For the downhole tool length  
2 calibration method, surveyed well details are not  
3 necessary.

4  
5 With the casing length calibration method  
6 (hereinafter CLC), the trajectory length or tool  
7 depth calibration, as performed by the processing  
8 means at the surface, uses the received signal from  
9 the tool 32 and references this signal against the  
10 conventionally obtained surface measured depth,  
11 obtained as described above, and the details of the  
12 well. That is, the individual casing length is used  
13 to calculate a depth correction factor  $\mu$  wherein

$$\mu_{CLC} = L_c / (D_2 - D_1),$$

14  
15  
16  
17 wherein

18  
19  $L_c$  = casing length;

20  $D_1$  = surface depth at the previous casing collar or  
21 joint;

22  $D_2$  = surface depth at the detected casing collar or  
23 joint, where  $D_2 > D_1$ ; and

24  $\mu_{CLC}$  = depth correction factor.

25

26 The depth correction factor  $\mu_{CLC}$  is used by the  
27 processing means to correct the conventionally  
28 obtained depth over the next downhole tool trajectory  
29 casing length.

30

1 With the downhole tool length calibration method  
2 (hereinafter TLC), the trajectory length or tool  
3 depth calibration is performed by the processing  
4 means located at the surface, for example. The  
5 processing means uses the received signal from the  
6 tool 32 and references this signal against the  
7 conventionally obtained surface measured depth to  
8 calculate a depth correction factor  $\mu$ . The  
9 correction factor  $\mu$  can be calculated as follows for  
10 equidistant sensor spacing (ie constant distance  
11 between sensors)

$$\mu_{TLC} = L_u / (D_n - D_{n-1}),$$

15 wherein

17  $L_u$  = tool sensor distance constant (ie the uniform  
18 distance between the sensors);  
19  $D_1$  = surface depth at the first tool sensor;  
20  $D_{n-1}$  = surface depth at the previous casing collar or  
21 joint;  
22  $D_n$  = surface depth at the detected casing collar or  
23 joint, where  $D_n > D_{n-1} > D_1$ ; and  
24  $\mu_{TLC}$  = depth correction factor.

26 The correction factor  $\mu$  can be calculated as follows  
27 for non-uniform sensor spacing (ie non-constant  
28 distance between sensors)

$$\mu_{TLC} = L_n / (D_n - D_{n-1}),$$

1

2     wherein

3

4      $L_n$  = tool sensor distance spacing (ie the non-uniform  
5     distant between the sensors);6      $D_1$  = surface depth at the first tool sensor;7      $D_{n-1}$  = surface depth at the previous casing collar or  
8     joint;9      $D_n$  = surface depth at the detected casing collar or  
10     joint, where  $D_n > D_{n-1} > D_1$ ; and11      $\mu_{TLC}$  = depth correction factor.

12

13     The depth correction factor  $\mu_{TLC}$  thus derived can be  
14     used by the processing means to correct the  
15     conventionally obtained depth over the next travelled  
16     spacing between the sensors (either uniform or non-  
17     uniform). If the total tool distance (that is the  
18     distance between the sensors provided in the tool 32)  
19     is less than the individual casing length, the  
20     derived multiple-calibrated correction factor  $\mu_{TLC}$  may  
21     be used to correct the conventionally obtained depth  
22     related input over the next downhole tool trajectory  
23     individual casing length.

24

25     It will be appreciated that the depth correction  
26     described above need not be performed in real-time.  
27     A running history file can be constructed using each  
28     surface-received signal from the tool 32 and after  
29     completion of a slickline run (downhole tool travel  
30     from surface to a depth and return to surface), the  
31     history file can be compared against a similar file



1 derived from the conventional depth measurement  
2 technique and the results analysed to interpret and  
3 evaluate the downhole tool run objectives and  
4 results.

5  
6 It will be appreciated that the use of a slickline as  
7 an antenna is not limited to facilitate an increase  
8 in accuracy of tool depth measurements. For example,  
9 the conventional method for detecting the status of a  
10 downhole tool or tools (that is a tool which is  
11 deigned to perform downhole functions such as setting  
12 plugs or isolating sections of the wellbore to deploy  
13 memory gauges) would be by a differential calculation  
14 involving the experience of the slickline operator in  
15 conjunction with correlated depth between distance  
16 travelled by the slickline (calculated using the  
17 conventional technique) and the location of a  
18 "nipple" in conjunction with the previously recorded  
19 "nipple" depth or tubing tally, or by other means  
20 involving physical stresses in the slickline (for  
21 example increased/decreased tension in the  
22 slickline). A "nipple" is a receptacle in which the  
23 downhole tool locates and latches into, or the  
24 position in the tubing or casing string for the  
25 deployment of the downhole tool to carry out its  
26 function.

27  
28 Once the downhole tool has been deployed or  
29 retrieved, the slickline winch operator typically  
30 sees a corresponding decrease or increase in the  
31 weight of the tool string equivalent to the weight of

1 the tool, which would be indicative of a successful  
2 deployment or retrieval.

3  
4 However, where the downhole tool is of a marginal  
5 weight so as not to show a significant difference in  
6 the weight of the tool string once it has been  
7 deployed or retrieved, or when circumstances inside  
8 the wellbore give a smaller indication than one of  
9 those described above (for example an obstruction in  
10 the tubing or such like), the status of the downhole  
11 tool is derived by conjecture until a time when the  
12 function of the tool can be operatively tested or the  
13 tool string is returned to the surface.

14  
15 As will be appreciated, these methods of ascertaining  
16 the status of downhole tools are not accurate and  
17 rely on the experience of the slickline winch  
18 operator, a careful tally of running and pulling  
19 weights, and accurate weight indication and depth  
20 correlation means. Even when these criteria have all  
21 been met, there is no guarantee that the downhole  
22 tool has been successfully deployed or retrieved  
23 correctly and where downhole tools which rely on the  
24 position of sliding sleeves are used, there is no  
25 indication of the position thereof until further  
26 tests have been carried out.

27  
28 The present invention facilitates a means to actively  
29 identify when a downhole tool has been deployed or  
30 retrieved etc by incorporating into the previously  
31 described apparatus one or more sensors (eg a

1 proximity or electrically connecting/disconnecting  
2 sensor) which activates the transmission of a signal  
3 via the slickline antenna which is indicative of the  
4 status of the tool (ie latched, unlatched, engaged,  
5 disengaged etc). This would provide a more reliable  
6 indication of the tool status in connection with the  
7 previously described depth correlation which  
8 substantially mitigates the possibility of human  
9 error in identifying whether the downhole tool has  
10 been correctly deployed or retrieved etc.

11

12 When a downhole tool has been deployed, retrieved or  
13 otherwise, it is normally the case to use a  
14 mechanical force in order to facilitate this  
15 deployment, retrieval or otherwise in order to  
16 operate a mechanism incorporated in the downhole tool  
17 in order to carry out the function of the tool. An  
18 example of this would be a running tool which is used  
19 to deploy a downhole plug which typically relies on  
20 the slickline operator to locate the tool in its  
21 downhole position using the conventional depth  
22 measurement. Thereafter, either pulling sharply on  
23 the slickline or rapidly slackening it induces a  
24 hammering effect on the tool whereby a pin (or a  
25 plurality thereof) are sheared to allow the tool to  
26 engage in a locking assembly, thus disconnecting the  
27 tool from the string, or a collar is pulled to  
28 retract such an assembly in order to release the tool  
29 from the locking assembly thus connecting the tool to  
30 the string.

31

1 A signal from a proximity sensor or the like can be  
2 propagated to the surface using the slickline as an  
3 antenna, the signal being received at the surface and  
4 causing, for example, a second signal to be  
5 transmitted from the surface to a relay provided on  
6 the (downhole) tool to electrically or  
7 electromechanically operate an automatic locking or  
8 unlocking device. This would eliminate the  
9 requirement for mechanical hammering to initiate the  
10 functioning of the downhole tool.

11  
12 Another application of the present invention would be  
13 during the deployment of downhole tools, a part or  
14 parts of the tool itself or the tool string can  
15 loosen or be disconnected from the tool or string.  
16 This can then require several runs into the wellbore  
17 in order to recover the tool or part thereof. This  
18 can be a very expensive process.

19  
20 To overcome this, the tools within the tool string or  
21 the parts of the tool themselves can be coupled  
22 together either electrically or magnetically wherein  
23 discontinuity of the electrical or magnetic  
24 connection triggers a signal or a plurality of  
25 signals which can be transmitted to the surface to  
26 indicate to the slickline operator that such an event  
27 is about to occur.

28  
29 Modifications and improvements may be made to the  
30 foregoing without departing from the scope of the  
31 present invention. For example, the foregoing

1 description relates to the use of a slickline as an  
2 antenna, but it will be appreciated that it is  
3 equally possible to use a braided line or a mono-  
4 conducting slickline. Additionally, the pulsed  
5 transmission to the surface could be replaced by a  
6 continuous type transmission, or alternatively, may  
7 be a pulsed or continuous two-way communication  
8 between the surface and a tool, using suitable  
9 transmitters and receivers (or transceivers) for such  
10 communications.

11  
12 Although the foregoing description relates to the use  
13 of a tool which detects the location and passage of  
14 collars in a cased wellbore, it will be appreciated  
15 that tools exist which are sensitive to non-collared  
16 pipe joints.

17  
18 Additionally, it will be appreciated that the  
19 communication system described herein enables the use  
20 of a slickline in combination with downhole tools,  
21 such as flow meters, pressure, temperature,  
22 gravitational, sonic and seismic sensors, downhole  
23 cameras and/or optic/IR sensors which have hitherto  
24 relied on electric (single- or multi-conductor)  
25 braided slicklines for operation.

26

27

1     CLAIMS:-

2

3     1.    A communication system for use in a wellbore,  
4     the system comprising a downhole tool, the downhole  
5     tool comprising a transmitter, the downhole tool  
6     being coupled to a wireline, wherein the downhole  
7     tool and wireline are adapted to be inserted into  
8     the wellbore, and a receiver located remotely from  
9     the transmitter, wherein the wireline is capable of  
10    running the downhole tool into the wellbore and is  
11    also capable of acting as an antenna for the  
12    transmitter.

13

14    2.    An apparatus according to claim 1, wherein the  
15    wireline is a slickline.

16

17    3.    An apparatus according to either of claims 1 or  
18    2, wherein the transmitter is further associated  
19    with, provided on, or an integral part of a tool  
20    string.

21

22    4.    An apparatus according to claim 3, wherein the  
23    downhole tool or tool string is suspended by the  
24    wireline.

25

26    5.    An apparatus according to either of claims 3 or  
27    4, wherein the transmitter transmits data collected  
28    or generated by the downhole tool or the like to the  
29    receiver.

30

1 6. An apparatus according to any preceding claim,  
2 wherein the receiver is located at, or near, the  
3 surface of the wellbore.

4

5 7. An apparatus according to any preceding claim,  
6 wherein the distance travelled by the downhole tool,  
7 the status of the downhole tool or other parameters  
8 of the downhole tool, can be transmitted to the  
9 receiver.

10

11 8. Apparatus according to any preceding claim,  
12 wherein the wireline is electrically insulated.

13

14 9. Apparatus according to any preceding claim,  
15 wherein the wireline is sheathed to facilitate  
16 electrical insulation.

17

18 10. A method of communication in a wellbore,  
19 comprising providing a downhole tool comprising a  
20 transmitter, coupling the downhole tool to a  
21 wireline, paying an end of the wireline and the  
22 downhole tool into the wellbore, and providing a  
23 receiver located remotely from the transmitter, such  
24 that the wireline acts as an antenna for the  
25 transmitter.

26

27 11. A slickline for use in a wellbore, wherein the  
28 slickline is provided with an insulating coating.

29

30 12. A slickline according to claim 11, wherein the  
31 insulating coating is an outer coating of the  
32 slickline.

1

2 13. A slickline according to either of claims 11 or  
3 12, wherein the coating comprises a stress/impact  
4 sensitive material.

5

6 14. A slickline according to any of claims 11 to  
7 13, wherein the insulating coating comprises at  
8 least one enamel material.

9

10 15. A distance measurement apparatus for measuring  
11 the distance travelled by a wireline, the apparatus  
12 comprising at least two sensors coupled to the  
13 wireline wherein the sensors are capable of sensing  
14 known locations in a wellbore.

15

16 16. Apparatus according to claim 15, wherein the  
17 wireline is a slickline.

18

19 17. Apparatus according to either of claims 15 or  
20 16, wherein the apparatus includes transmission  
21 means for transmitting data collected by the at  
22 least two sensors to a receiver located remotely  
23 from the apparatus.

24

25 18. Apparatus according to claim 17, wherein the  
26 wireline is capable of acting as an antenna for the  
27 transmission means.

28

29 19. Apparatus according to either of claims 17 or  
30 18, wherein the sensors are coupled at or near a  
31 downhole tool whereby the distance travelled by the



1 tool, and the location of the tool within the  
2 wellbore, can be calculated.

3

4 20. Apparatus according to any of claims 17 to 19,  
5 wherein the wireline is electrically insulated.

6

7 21. A method of measuring the distance travelled by  
8 a wireline, the method comprising the steps of  
9 coupling at least two sensors to the wireline, the  
10 at least two sensors being capable of sensing known  
11 locations in a wellbore; running the wireline into  
12 the wellbore; calculating the depth of the at least  
13 two sensors; generating a signal when each of the at  
14 least two sensors pass said known locations; using  
15 the signals to calculate a depth correction factor;  
16 and correcting the calculated depth using the depth  
17 correction factor.

18

19 22. A downhole tool comprising coupling means to  
20 allow the tool to be attached to a wireline, at  
21 least two sensors capable of detecting known  
22 locations in a wellbore and generating a signal  
23 indicative thereof, and a transmission means capable  
24 of transmitting the signals.

25

26 23. A downhole tool according to claim 22, wherein  
27 the wireline acts as an antenna for the transmission  
28 means.

29

30 24. A downhole tool according to either of claims  
31 22 or 23, wherein the coupling means comprises a  
32 rope-socket.

1

2 25. A downhole tool according to claim 24, wherein  
3 the rope-socket is provided with signal coupling  
4 means to couple the signals generated by the  
5 transmission means to the wireline.

6

7 26. A downhole tool according to any of claims 20  
8 to 23, wherein the downhole tool is powered by a DC  
9 power supply.

10

11 27. A method of tracking a member in a wellbore,  
12 the method comprising providing at least two sensors  
13 on the member, inserting the member and said sensors  
14 into the wellbore, obtaining information indicating  
15 the position of the sensors in the wellbore, and  
16 determining the distance travelled by said member  
17 from said sensor information.

18

19 28. Apparatus for indicating the configuration of a  
20 downhole tool or tool string, the apparatus  
21 comprising at least two sensors capable of sensing a  
22 change in the configuration of the downhole tool or  
23 tool string and generating a signal indicative  
24 thereof, and a transmission means electrically  
25 coupled to the at least two sensors for transmitting  
26 the signals to a receiver.

27

28 29. Apparatus according to claim 28, wherein the  
29 downhole tool is preferably suspended in a borehole  
30 using a wireline, and the wireline is capable of  
31 acting as an antenna for the transmission means.

32

1 30. Apparatus according to either of claims 28 or  
2 29, wherein the transmitter facilitates the  
3 transmission of data collected by the sensors to the  
4 receiver.

5

6 31. Apparatus according to any of claims 28 to 30,  
7 wherein the transmission means comprises a  
8 transmitter.

9

10 32. Apparatus according to any of claims 28 to 31,  
11 wherein the receiver is located at, or near, the  
12 surface of the borehole.

13

14 33. Apparatus according to any of claims 26 to 30,  
15 wherein the apparatus is arranged whereby it can  
16 facilitate two-way communication between the  
17 downhole tool and the receiver.

18

19 34. Apparatus according to any of claims 28 to 32,  
20 wherein the sensors comprise electric or magnetic  
21 sensors which are coupled to the downhole tool  
22 wherein a discontinuity of the respective electric  
23 or magnetic connection triggers a signal by each  
24 sensor.

25

26 35. Apparatus according to any of claims 29 to 34,  
27 wherein the wireline is electrically insulated.

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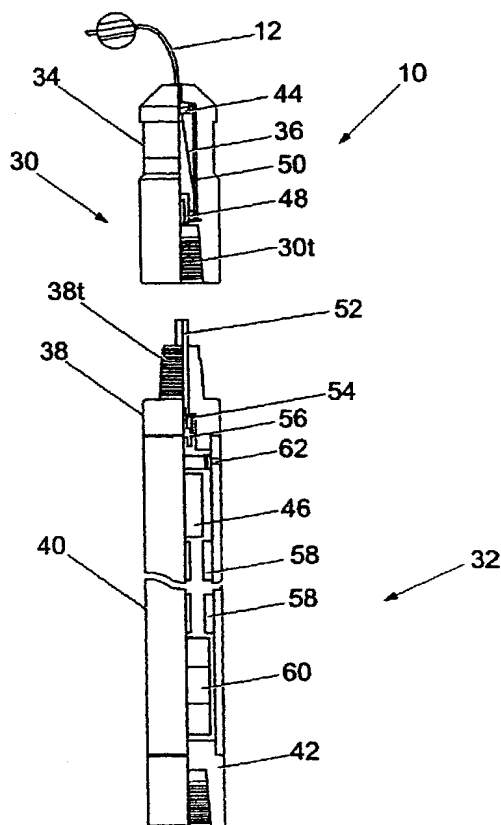
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[Continued on next page]

(54) Title: **APPARATUS AND METHODS FOR MEASURING DEPTH**



(57) Abstract: A communication system for use in a wellbore, a down-hole tool, and a method includes a transmitter coupled to a wireline, and a receiver located remotely from the transmitter. The wireline is capable of acting as an antenna for the transmitter. The wireline is a slickline, and the transmitter may be associated with, provided on, or an integral part of a downhole tool or tool string. The transmitter typically transmits data collected or generated by the downhole tool or the like to the receiver, which is preferably located at, or near, the surface of the wellbore. The wireline is typically provided with an insulating coating. Also, a distance measurement apparatus and a method for measuring the distance travelled by a wireline includes at least one sensor coupled to the wireline, and the sensor is capable of sensing known locations in a wellbore.

WO 01/20129 A3

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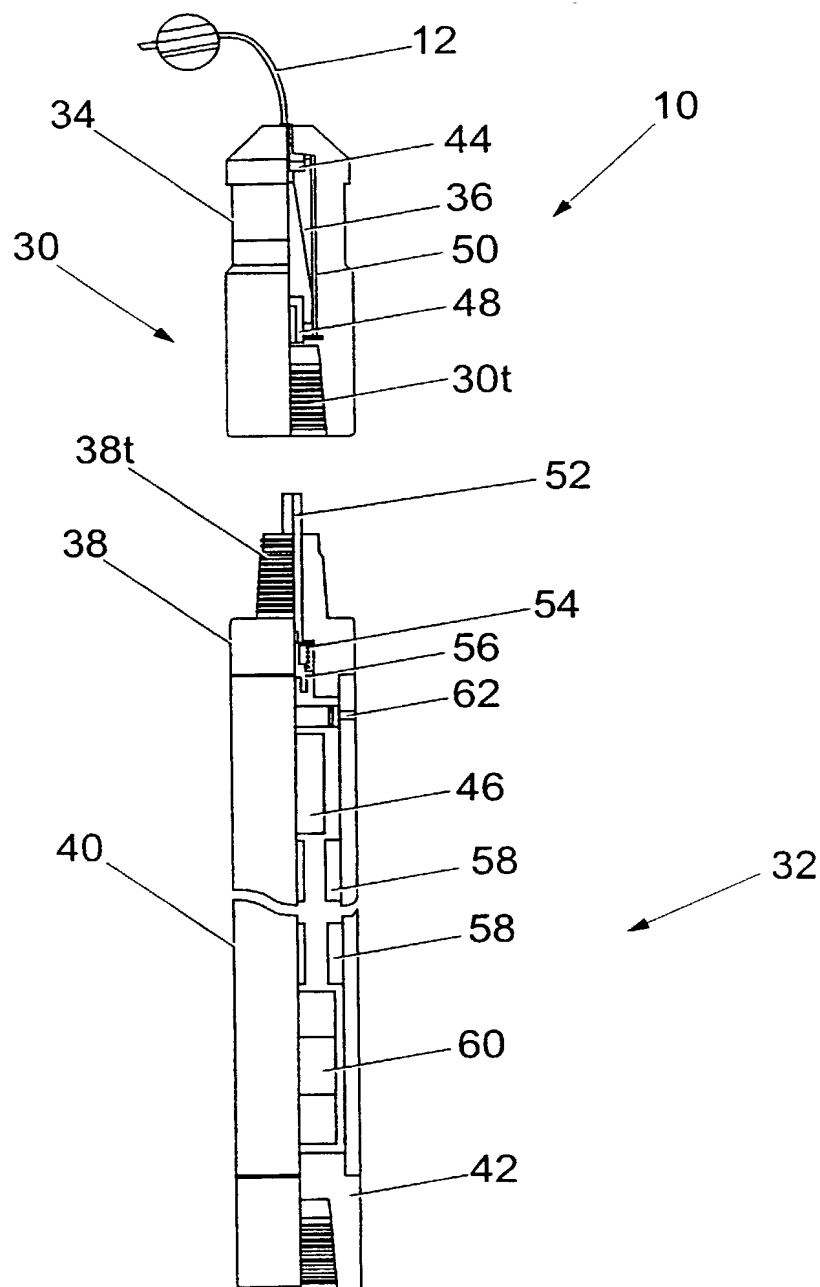


Fig. 1

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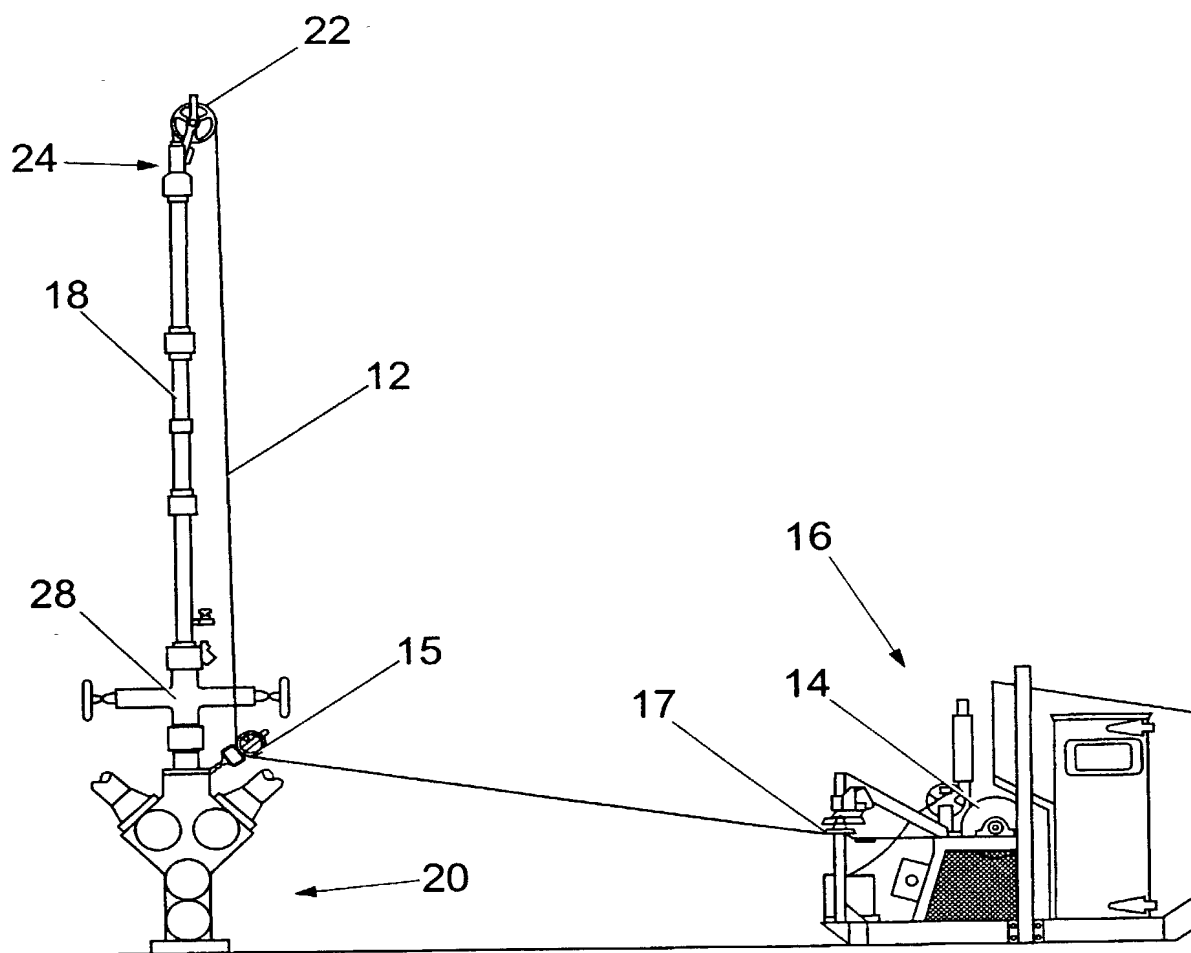
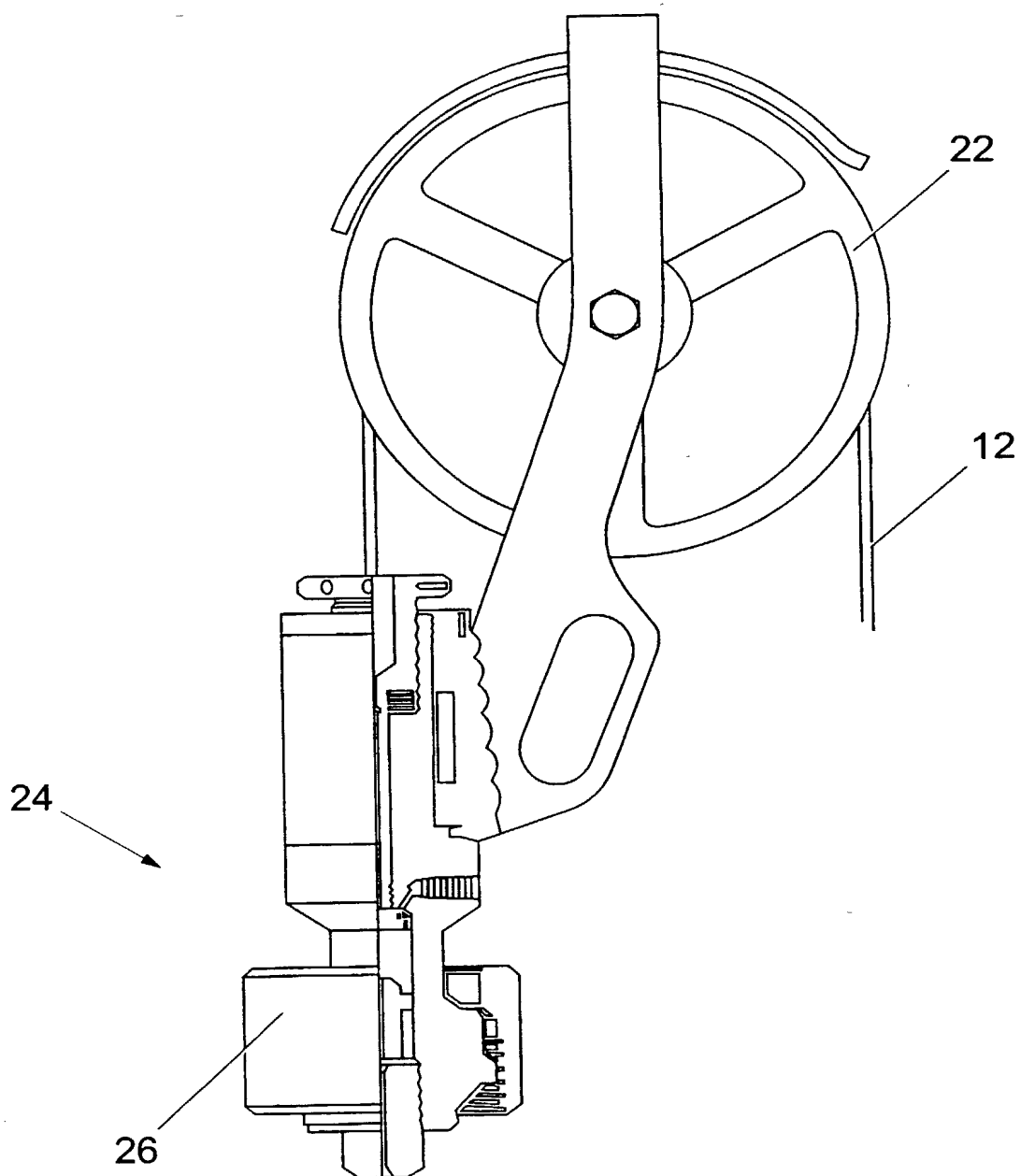


Fig. 2

3 / 5



*Fig. 3*

4 / 5

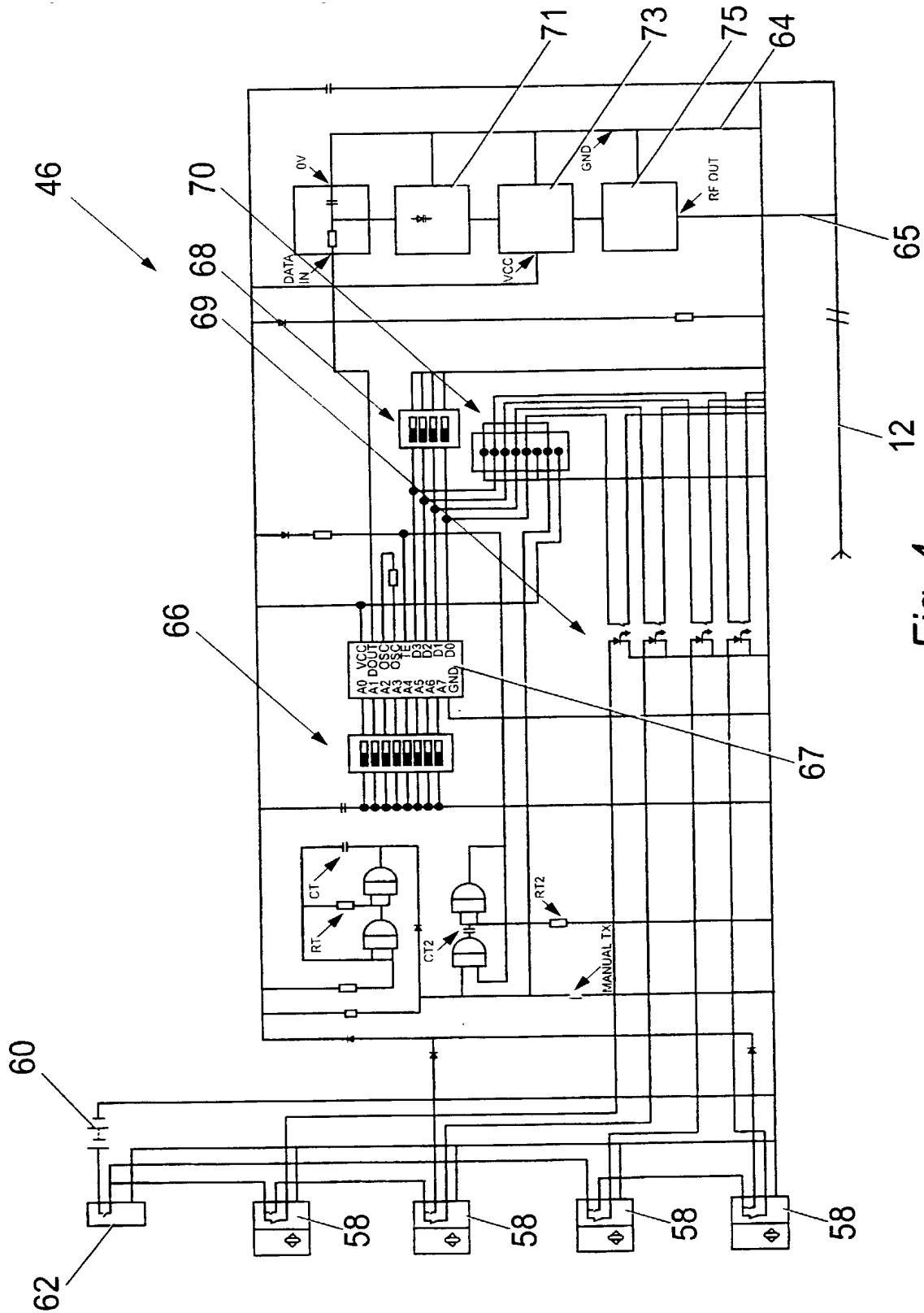


Fig. 4



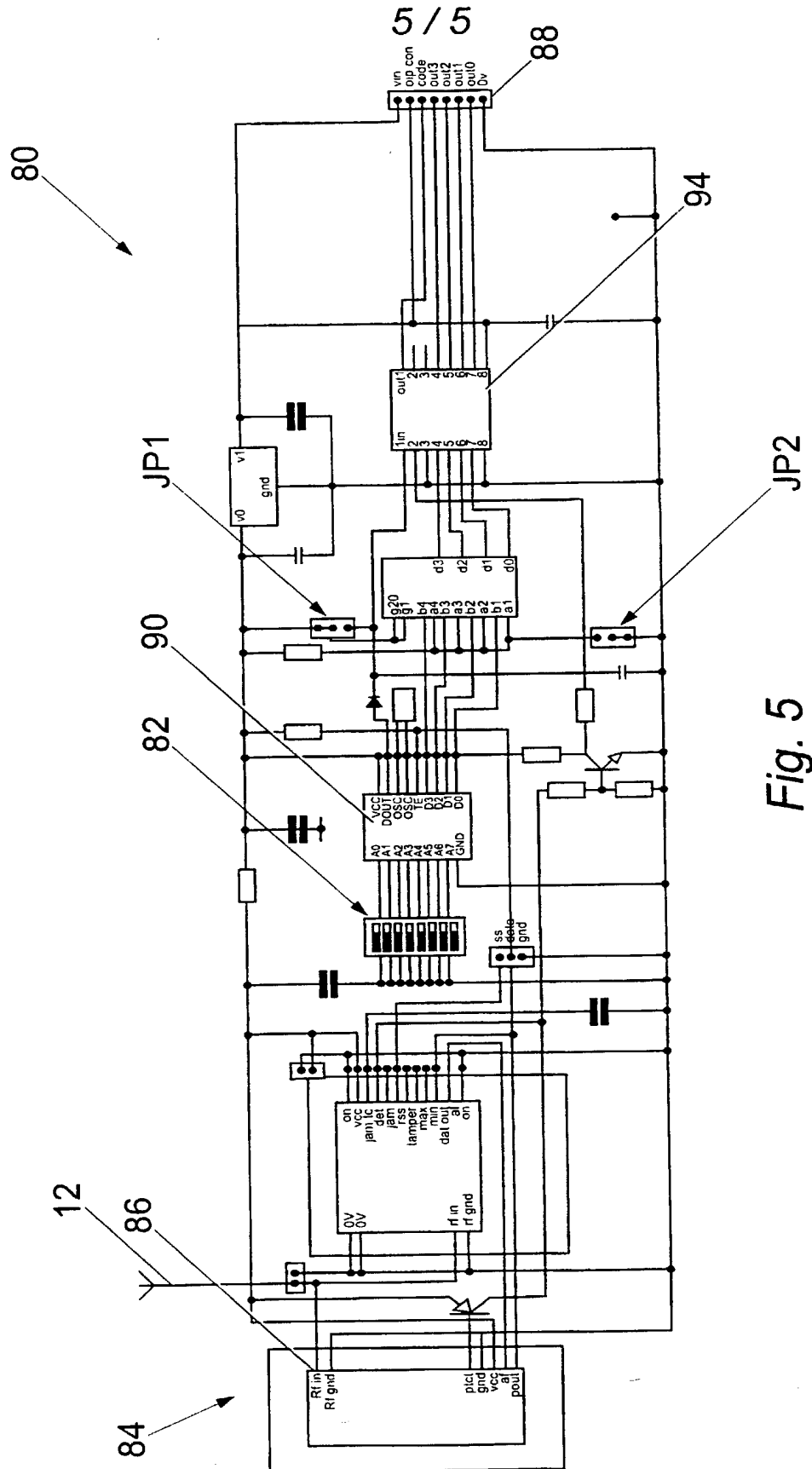


Fig. 5

1

**DECLARATION AND POWER OF ATTORNEY**

As a below named inventor, I hereby declare that:

My residence, post office address and citizenship are stated below next to my name.

I believe I am the original, first and sole inventor (if only one name is listed below) or an original, first and joint inventor (if plural names are listed below) of the subject matter which is claimed and for which a patent is sought on the invention entitled:

**APPARATUS AND METHODS RELATING TO DOWNHOLE OPERATIONS**

the specification of which (check one)

☐ is attached hereto.

☒ was filed on \_\_\_\_\_ as United States Application Serial No. \_\_\_\_\_ or PCT International Application No. PCT/GB00/03491 and was amended on October 11, 2001 and March 14, 2002 (if applicable).

I hereby state that I have reviewed and understand the contents of the above-identified specification, including the claims, as amended by any amendment referred to above.

I acknowledge the duty to disclose information which is material to the examination of this application in accordance with Title 37, Code of Federal Regulations, §1.56.

I hereby claim foreign priority benefits under Title 35, United States Code §119(a)-(d) of any foreign application(s) for patent or inventor's certificate listed below and have also identified below any foreign application for patent or inventor's certificate having a filing date before that of the application on which priority is claimed:

[illegible]

Yes [X] No [ ]

Yes [ ] No [ ]

Yes [ ] No [ ]

I hereby claim the benefit under Title 35, United States Code, §119(e) of any United States provisional application(s) listed below.

(Application Number) (Filing Date)

(Application Number) (Filing Date)

I hereby claim the benefit under Title 35, United States Code, §120 of any United States application(s) listed below and, insofar as the subject matter of each of the claims of this application is not disclosed in the prior United States application in the manner provided by the first paragraph of Title 35, United States Code, §112, I acknowledge the duty to disclose material information as defined in Title 37, Code of Federal Regulations, §1.56 which occurred between the filing date of the prior application and the national or PCT international filing date of this application:

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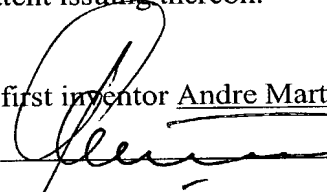
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I hereby declare that all statements made herein of my own knowledge are true and that all statements made on information and belief are believed to be true; and further that these statements were made with the knowledge that willful false statements and the like so made are punishable by fine or imprisonment, or both, under Section 1001 of Title 18 of the United States Code, and that such willful false statements may jeopardize the validity of the application or any patent issuing thereon.

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